United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued December 7, 2007 Decided May 23, 2008

No. 06-1178

COGENERATION ASSOCIATION OF CALIFORNIA AND
ENERGY PRODUCERS AND USERS COALITION,
PETITIONERS

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

CALIFORNIA ELECTRICITY OVERSIGHT BOARD AND
PACIFIC GAS & ELECTRIC COMPANY,
INTERVENORS

On Petition for Review of Orders of the
Federal Energy Regulatory Commission

Donald E. Brookhyser argued the cause for petitioners. With him on the briefs was *Michael Alcantar*.

Jeffery S. Dennis, Attorney, Federal Energy Regulatory Commission, argued the cause for respondent. With him on the brief were *John S. Moot*, General Counsel, and *Robert H. Solomon*, Solicitor.

Mark D. Patrizio argued the cause for intervenors Pacific Gas & Electric Company and California Electricity Oversight Board in support of respondent. With him on the brief were *Erik N. Saltmarsh* and *Jeffrey A. Diamond*.

Before: RANDOLPH, GRIFFITH, and KAVANAUGH, *Circuit Judges*.

Opinion for the Court filed by *Circuit Judge* GRIFFITH.

Opinion dissenting by *Circuit Judge* RANDOLPH.

GRIFFITH, *Circuit Judge*: Pacific Gas & Electric Company ("PG&E") provides electricity transmission services for customers in northern and central California. A small fraction of the company's users are "standby customers": entities that generate their own electricity, but contract with PG&E for back-up supply in the event of power outages. The petitioners in this case, two unincorporated associations comprised of PG&E standby customers, challenge how the utility determines the price for their service. At issue is whether the Federal Energy Regulatory Commission reasonably approved the unique rates PG&E applies to standby customers. We hold that the agency's decision was reasonable and therefore deny the petition for review.

I.

A.

Under the Federal Power Act ("Act"), 16 U.S.C. § 791 *et seq*., the Federal Energy Regulatory Commission ("FERC" or "Commission") has exclusive authority to regulate the transmission and sale of electricity in interstate commerce. *Id.*

§ 824(b). Every utility must file with the Commission a copy of its rates and charges. *Id.* § 824d(c). If a utility wants to change its pricing, the company must give sixty days' notice to the Commission, *id.* § 824d(d), which has the authority to hold hearings on the proposed change, *id.* § 824d(e), and the responsibility to ensure that all rates are "just and reasonable," *id.* § 824d(a). If the Commission does not intervene, the rate goes into effect after the sixty days pass. *See Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 952–53 (D.C. Cir. 1983); *Me. Pub. Utils. Comm'n v. FERC*, 454 F.3d 278, 282–83 (D.C. Cir. 2006).

This litigation involves a proposed rate change filed by PG&E on January 13, 2003 that sought to boost its annual revenue from $379 million to $545 million. For all customers except the standby class, PG&E applied what is called the "12-coincident peak method" ("12-CP") to determine the new rate. Because of the unpredictable nature of the demand of standby customers, however, the utility determined the proposed rate for that class using a formula called the "probabilistic method."

Both formulas set prices on the basis of past demand. The 12-CP method looks to the share of each customer class when demand is at its zenith. The utility begins by identifying the "system peak," the hour in a given month when the system experiences its greatest demand for electricity. It then determines the percentage of peak usage that each class draws during that hour, averages the results over the course of a year, and divides the revenue pie accordingly.

The probabilistic method PG&E applies to the standby customers is more complex. Under this method, rates are based on the percentage of "contract demand" the standby class is likely to use, rather than usage at the time of system peak. Contract demand is the maximum amount of electricity a standby customer can draw under the terms of its contract. For example, a standby customer may contract for up to 100 megawatts ("MW"), which means the customer can draw up to that amount of power at any time. Because standby customers typically generate electricity for their own use and only draw electricity from PG&E because of power outages, PG&E does not charge them the full amount of contract demand. Instead, using data reflecting historical usage by the standby customers, PG&E determines what percentage of contract demand that class must shoulder. This percentage represents the "cost allocation factor." For example, if contract demand is 100 MW and past usage yields a cost allocation factor of 10%, the standby customer only pays for 10 MW of service, even though it has a right to draw up to 100 MW.

This cost allocation factor, moreover, is made up of two parts: a regional transmission allocation factor and a local transmission allocation factor. This division reflects the different pricing factors that apply at different stages in the transmission of electricity. PG&E assesses the standby customers' share of regional and local transmission costs, identifies an allocation factor for each, and then takes the weighted average of those two factors to produce the overall cost allocation factor. A witness for PG&E testified that the company originally developed the regional factor for allocating the cost of generating electricity and then determined that this factor would reasonably reflect the costs of regional transmission as well. As for the local allocation factor, PG&E randomly selected several standby customers, calculated their total contract demand, and then took note of their actual usage for each hour during the "peak period" (Monday through Friday, 8:30 a.m. to 9:30 p.m., May through October) to produce a curve. The company then identified the ninetieth percentile point on that curve: the hour where electricity usage by the sample of standby customers was greater than nine out of every ten hours during the peak period. PG&E chose this point regardless of when system peak occurred. Finally, the company calculated the demand at the ninetieth percentile point as a percentage of the sample's total contract demand to produce the local allocation factor.

Contract demand for the standby class is 600 MW. In its proposed allocation, PG&E assigned a 12% factor for the regional costs and a 38% factor for the local costs, producing a weighted average of approximately 27%.[1] That is to say, the standby class would pay 27% of the cost for 600 MW. Under the proposal, the standby class went from paying $0.26 per kilowatt to $0.35 for the same.

B.

After PG&E filed its proposed rate increase, the Commission suspended the new rates and scheduled a hearing to determine whether they were "just and reasonable." *Pac. Gas & Elec. Co.*, 102 F.E.R.C. ¶ 61,270 (2003). The administrative law judge ("ALJ") issued a summary disposition on one issue and the parties resolved their dispute as to all other issues, except for the question now before us. *See Pac. Gas & Elec. Co.*, 110 F.E.R.C. ¶ 63,026, at 65,049 (2005) (describing procedural history). The ALJ concluded in principle it was reasonable to assign unique rates to standby customers based on contract demand because they were not similarly situated to other classes. The ALJ found that demand by standby customers is random; they typically

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[1] PG&E adopted these regional and local allocation factors for its standby class, as well as the percentages for producing a weighted average, in a previous rate settlement.

cannot predict when their generating units will go offline and require electricity from PG&E. *Id.* at 65,053 ("Having PG&E standing ready to provide service on demand is a valuable service and rates based on this potential use of power, rather than actual use are not *per se* unreasonable.").

Turning to the particular method PG&E used to determine the standby customers' share of regional and local transmission costs, however, the ALJ held that recent data did not support the methodology PG&E used for its standby customers. *Id.* at 65,054–56. Instead, the ALJ concluded that more recent data supported applying the 12-CP method, *id.* at 65,055, and observed that "[w]hile standby service is unpredictable, the relatively small size of the standby class in this case mitigates this difficulty," *id.* at 65,056. PG&E and FERC both filed exceptions to the decision, which the standby customers also opposed.

On review, the Commission agreed with the ALJ that the standby class is not similarly situated to the other classes and that a rate based on contract demand may be lawful if supported by sufficient data on past demand. *Pac. Gas & Elec. Co.*, 113 F.E.R.C. ¶ 61,084, at 61,323 (2005). The Commission, however, reversed the ALJ's conclusion that the 12-CP method was appropriate and instead held that substantial and persuasive evidence supported PG&E's proposed allocation of costs to the standby customers based on the application of the probabilistic method to contract demand. *Id.* at 61,326. FERC denied a subsequent request for rehearing, *Pac. Gas & Elec. Co.*, 114 F.E.R.C. ¶ 61,324 (2006), and the standby class filed a timely petition for review in this court challenging both the methodology and the overall cost allocation factor that PG&E proposed.

We have jurisdiction under 16 U.S.C. § 825*l*(b) and review the Commission's order under the arbitrary and capricious standard of the Administrative Procedure Act, 5 U.S.C. § 706(2)(A). *See Sithe/Independence Power Partners v. FERC*, 165 F.3d 944, 948 (D.C. Cir. 1999). The Commission's factual findings will stand if supported by substantial evidence. 16 U.S.C. § 825*l*(b); *see also Fla. Mun. Power Agency v. FERC*, 315 F.3d 362, 365 (D.C. Cir. 2003). Moreover, we "will affirm the Commission's orders so long as FERC 'examine[d] the relevant data and articulate[d] a . . . rational connection between the facts found and the choice made.' " *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (*citing Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)). Where the evidence might support more than one rational interpretation, "the question we must answer . . . is not whether record evidence supports [the petitioner's] version of events, but whether it supports FERC's." *Fla. Mun. Power Agency*, 315 F.3d at 368.

II.

Petitioners' sundry arguments advance one simple claim: The Commission's decision to approve PG&E's proposed rate increase violates the "cost-causation principle." "[U]nder section 205(a) of the Federal Power Act, a utility may charge only rates that are 'just and reasonable.' Interpreting that mandate, we have explained that such rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity. We have consistently upheld rates based on such a cost-causation principle." *Sithe/Independence Power Partners v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002) (internal quotation marks and citations omitted). The standby customers argue that the Commission's decision to approve PG&E's methodology based on contract demand, and the weighted 27% allocation factor that methodology produced, violated the cost-causation principle and lacked the support of substantial evidence in the record. We disagree.

A.

The probabilistic methodology is a reasonable means to account for the special costs that standby customers impose on PG&E. The Commission concluded and the petitioners do not contest that the standby customers are not similarly situated to the company's other customer classes. As James Ross, a witness for the petitioners, stated:

> PG&E provides standby service to replace the generation ordinarily serving the customer during periods when that customer generation is out of service due to unscheduled and scheduled outages. Thus, the supply of standby service during periods of system coincident peaks differs from full requirements service, because it is typically a function of random outages associated with the customer generation equipment failure.

Prepared Direct Testimony of James A. Ross, 3–4. Moreover, petitioners concede that PG&E incurs costs by standing ready to serve the random demands of standby customers. Petitioners' Reply Br. at 2 ("[The petitioners] do[ ] not contest the judge's finding that PG&E incurs costs to stand by ready to serve."). They cite to the ALJ's finding at ¶ 40 of the initial decision, which reads: "PG&E incurs costs (a 'capacity requirement') to be prepared and to 'stand ready' to provide service to the standby class at the contract demand level when needed, but only when needed." 110 F.E.R.C. ¶ 63,026, at 65,053 (internal quotation marks omitted).

Despite this concession, petitioners argue that standby customers only impose costs on PG&E insofar as they contribute to the system peak and that the 12-CP method, which apportions costs according to usage at system peak, is therefore the reasonable allocation method. To support this claim, the petitioners principally rely on the testimony of Ben Morris, a PG&E expert witness who testified on transmission planning at the company. Tr. of Aug. 31, 2004 Hr'g at 268–82. Morris testified that transmission planners measure the adequacy of the system by assessing its ability to meet demand at system peak. To make this assessment, planners forecast both anticipated load and the generation necessary to satisfy that load. With these results in hand, the planners also model "contingencies" — failures of either generation or transmission facilities. If the results show that the transmission system may fail to satisfy demand at system peak, then the planners propose additions and improvements to the system.

We conclude that the Commission reasonably approved as "just and reasonable" the rate for standby customers based on the probabilistic method because substantial evidence in the record shows that the unpredictability of standby customer demand imposes costs not captured by measuring that class's contribution to system peak. To reach this conclusion, the Commission relied primarily on the testimony of Andrew Bell, a rate expert who testified on behalf of PG&E. Bell explained that the standby class is different from other classes because the demand it places on the system is both variable and unpredictable. Tr. of Aug. 31, 2004 Hr'g at 190. Nonetheless, under the contract PG&E must provide service to the standby customers on demand. *Id.* at 193, 244–45.

> Because standby service customers' usage of utility-supplied backup power is by its very definition subject

> to unpredictable and fundamentally random variations, the utility must make adequate reserve capacity available to serve foreseeable potential loads of the standby class. In any given month, the standby class' maximum demand might or might not occur coincident with system peak. PG&E has accounted for this inherent uncertainty by using statistical methods to estimate what fraction of the total contract capacity should be treated as a reserve against the contingency of multiple on-peak outages for individual standby customers' generation equipment.

Prepared Rebuttal Testimony of Andrew M. Bell, Exhibit PGE 45-5.

The 12-CP method does not sufficiently allocate costs to the standby class because the probability of that class's maximum demand coinciding with system peak is statistically low, but not so low that PG&E can ignore that possibility in its capacity planning.[2] Assigning cost responsibility to the standby class on the basis of its share of system peak — in most months quite low — would not capture all the costs that class imposes on PG&E, which must plan for the possibility

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[2] The standby class is not the only class whose maximum demand does not often coincide with system peak. As one example, Bell mentioned the street lights rate class, which has a similar overall load to the standby class. Tr. of Aug. 31, 2004 Hr'g at 191–92. The demand this class places upon the system, however, is predictable. PG&E does not have to plan for the possibility that this class might place significant demand on the system at or near the time of system peak. *Id.* at 192 ("I know when the street lights are going to come on, they're going to come on when it gets dark. The standby class, there's . . . no physical predictability or reason for when the maximum demand will be higher than the coincident peak demand during the coincident peak.").

that the standby customers could draw up to contract demand at the time of system peak. *See* Tr. of Aug. 31, 2004 Hr’g at 238–47.

The petitioners claim that Morris’s testimony about how PG&E undertakes system transmission planning undermines this rationale. *Id.* They suggest that only a method that measures contribution to system peak is reasonable because PG&E incurs its costs by expanding to meet demand at that point. The purpose of such planning, however, is to identify the need for incremental additions and improvements to the system. *Id.* at 268, 275, 278. As the Commission concluded, this account of planning at the macro level does not provide a complete picture of how PG&E incurs costs to meet the random demand of the standby customer class. *See Pac. Gas & Elec. Co.*, 114 F.E.R.C. ¶ 61,324, para. 11 & n.16 (2006).

Moreover, FERC has approved a methodology based on contract demand in the past. For example, in *Central Power & Light Company*, 47 F.E.R.C. ¶ 61,339 (1989), the Commission considered a similar challenge to cost allocation based on contract demand brought by a standby customer. The agency upheld the methodology: “[The utility] is contractually obligated to provide service to [the standby customer] and [the utility] incurs costs to stand ready to provide service. . . . Therefore, allocating demand related costs to [the standby customer] based on its contract demand is reasonable.” *Id.* at 62,166. Citing testimony that the demand imposed by the standby customer is “inherently unpredictable,” the Commission further held: “We believe that [the utility] properly allocated costs differently for its partial requirements class customers because they are not similarly situated to [the utility’s] full requirements customers. Consequently, we find that [the utility’s] use of contract demands for its partial requirements class customers in this case did not constitute undue discrimination." *Id.* at 62,166–67.[3]

B.

Having decided that FERC did not act arbitrarily and capriciously in approving a method based on contract demand to determine the rate for the standby class, we must still decide whether the specific 27% cost allocation factor PG&E proposed was reasonable and supported by substantial evidence in the record. As mentioned, this percentage represents the weighted average of the 12% regional allocation factor and the 38% local allocation factor. Data in the record shows that this regional allocation reflects the standby customers' actual usage. As Bell testified,

> The 12 percent factor, after being applied to 600 MW of contracted standby demand, provides cost recovery

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[3] The ALJ in *Central Power & Light Company* found that the utility "was at all times either serving [the standby customer's] contract demand or was maintaining spinning reserves to allow it to serve . . . contract demand if called upon to do so." 47 F.E.R.C. at ¶ 62,165. In the present case, the agency did not find that PG&E had to maintain the full amount of contract demand as a spinning reserve on line at all hours. Rather, as Bell testified, "PG&E has accounted for this inherent uncertainty by using statistical methods to estimate what fraction of the total contract capacity should be treated as a reserve against the contingency of multiple on-peak outages for individual standby customers' generation equipment." Prepared Rebuttal Testimony of Andrew M. Bell, Exhibit PGE 45-5. The different rates reflect this variance: the standby customer in *Central Power* paid 100% of contract demand, 47 F.E.R.C. at ¶ 62,163, whereas the standby customers in the present case pay 27% of contract demand.

> for somewhat less than an 80 MW share of regional transmission facilities. The table at page 13 of Mr. Ross' testimony shows that the maximum non-coincident peak demand of the standby class exceeded this level during five of the twelve calendar months of 2001 . . . and that at least two of these occurrences were during the weekday partial-peak time-of-use period . . . and thus were at or near times when this level of standby usage would coincide with the system peak.

Prepared Rebuttal Testimony of Andrew M. Bell, Exhibit PGE 45-5, 6. The standby customers dismiss this evidence because it refers to usage at times other than system peak, but, as we have already explained, FERC did not act unreasonably in approving a method that does not rely upon usage at system peak to set the standby customer rate.

Although PG&E first arrived at the 38% local allocation factor in 1993, Bell testified that more recent data supports this calculation. Dividing PG&E's service territory into six broadly defined geographic areas and drawing on data from 2001, he explained that "the single largest individual standby customer within each zone typically accounts for between 29 and 48 percent of the total contracted standby load in that zone," and that the "weighted average . . . is 37 percent, when expressed as a fraction of the total standby load within each zone."[4] *Id.* at 45-6, 7. This weighted average is comparable to

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[4] As the intervenors clarify, 37% represents the "weighted average share across all six areas for the largest standby load in each area as a percentage of total contracted demand in each area." Intervenors' Br. at 7 n.3. In his testimony, Bell went on to explain that if the company had performed the same analysis but considered the two largest customers in each zone, the figure would have been even

the 38% allocation factor PG&E proposed.

III.

For the reasons stated in this opinion, we deny the petition for review.

So ordered.

higher. Prepared Rebuttal Testimony of Andrew M. Bell, Exhibit PGE 45-7.

RANDOLPH, *Circuit Judge*, dissenting: I agree with majority's statement of the cost causation standard that governs the Commission's ratemaking decisions. Maj. Op. at 6-7. But I disagree that the Commission has satisfied that standard. Commission counsel admitted at oral argument that nowhere in the record is there a calculation of PG&E's costs for standing ready to serve petitioners. Without that number or even a rough approximation of it, the Commission could not determine whether the rate PG&E proposed related to the costs these standby customers imposed. It is no answer to say that the standby customers must be imposing *some* cost on PG&E or that the 12-CP system may not adequately account for the standby customer's unpredictable usage. The questions remain – *what* is the amount of the cost and does that amount justify a rate four times higher than the rate PG&E would have charged under its 12-CP system. The Commission never answers either question and neither does the majority opinion.